Application 22-05-002
Exhibit No.: CLECA-02

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027.	**Application 22-05-002** **(Filed May 2, 2022)**
And Related Matters	**Application 22-05-003** **Application 22-05-004** **(Consolidated)**

Rebuttal Testimony of

SAM HARPER

on behalf of

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

May 12, 2023

HARPER
ADVISORY

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REBUTTAL TESTIMONY OF SAM HARPER
ON BEHALF OF CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

EXECUTIVE SUMMARY

This rebuttal testimony responds to the testimony of parties in this proceeding including support for increased Base Interruptible Program (BIP) incentive levels proposed by the Joint Demand Response (DR) Parties and the Industrial Pumping Customers (IPC); support for inclusion of DR customer representation on the Advisory Committee for the Market-Integration Efficacy Study proposed by The California Efficiency + Demand Management Council (the Council); and responses to proposals related to the BIP program by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates). This rebuttal testimony is presented by Sam Harper on behalf of the California Large Energy Consumers Association (CLECA).[1] Sam

[1] CLECA is an organization of large, high load factor industrial customers located throughout the state; the members are in the cement, steel, industrial gas, medical gas, pipeline, beverage, cold storage, and minerals processing industries, and share the fact that electricity costs comprise a significant portion of

Harper's statement of qualifications is included as Attachment A to his direct testimony dated April 21st 2023.

BIP INCENTIVE LEVELS

Q DO OTHER PARTIES SUPPORT BIP INCENTIVE LEVELS HIGHER THAN PROPOSED IN THE UTILITY DR APPLICATIONS?

A Yes, the Joint DR Parties and IPC support higher BIP incentive levels. The Joint DR Parties have a long history of DR participation reflecting deep program experience and knowledge of participating customer challenges. The Joint DR Parties explain, "in order to avoid any program attrition and to meet enrollment projections, incentive rates for both PG&E and SCE need to be increased to entice customers and ensure strong performance from larger customers."[2] IPC represents current, past, and future BIP participants bringing valuable perspective on the incentives necessary for program growth aligned with the stated goals SCE and PG&E. IPC states that, "Given the economic costs and safety considerations of interrupting power to large industrial facilities, the incentive levels for participation need to be substantial and sufficient to make the program worthwhile for participation."[3] IPC further explains that, "Given that

their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite renewable generation. CLECA has been an active participant in Commission regulatory proceedings since the mid-1980s, and all CLECA members engage in Demand Response (DR) programs to both promote grid reliability and help mitigate the impact of the high cost of electricity in California on the competitiveness of manufacturing. CLECA members have participated in the Base Interruptible Program (BIP) and its predecessor interruptible and non-firm programs since the early 1980s.

[2] Ex. JDRP-01 at p. 18, line 15 - line 18.

[3] Ex. IPC-01 at p. 2, line 17 - line 19.

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the avoided costs have been increased by a large amount, this should also have an upward effect on the BIP incentive levels approved for this program cycle."[4] I agree.

Q HOW DO THE JOINT DR PARTIES AND IPC PROPOSE TO INCREASE BIP INCENTIVES?

A The Joint DR Parties and IPC both propose to increase Southern California Edison (SCE) BIP incentives for sub-transmission voltage customers, citing the significant gap compared to the lower voltage classes. IPC explains,[5]

> *SCE should reevaluate the incentive levels for Sub-Transmission voltage customers and either propose commensurately higher incentive levels in its rebuttal testimony, or explain why it believes such low incentive levels for the Sub-Transmission class are appropriate. Participants have to decide if it makes economic sense for them to participate in the BIP and this lower incentive for the Sub-Transmission voltage customers is an impediment to robust program participation.*

The Joint DR Parties explain,[6]

> *Specifically, the significantly lower incentive rate for 50 + kV customers may not continue to meet many of these customers' cost to curtail. Additionally, the Joint DR Parties have noted in our own data that this category of customer makes up a significant proportion of the SCE BIP MW base and often times is the highest performing voltage tier. Therefore, we believe that an incentive rate for 50 + kV*

[4] Ex. IPC-01 at p. 2, line 22 - line 24.
[5] Ex. IPC-01 at p. 8, line 15 - line 21.
[6] Ex. JDRP-01 at p. 19, line 12 - line 19.

customers that is more closely aligned, in a 5% to 10% variance, with the other 2 incentive categories would help ensure continued strong performance and participation from the customers in this category.

The Joint DR Parties further propose to change the Pacific Gas and Electric (PG&E) BIP incentives by adding a fourth tier for potential load reduction above 5,001 kW with a $2.5/kW higher incentive for both seasons.[7]

Joint DR Parties' Proposed Revision to PG&E's BIP Incentive Rates

Line No.	Potential Load Reduction	2021-2023 Nov- April	2021-2023 May-Oct	2024-2027 Nov-April (Proposed)	2024-2027 May-Oct (Proposed)
1	1 to 500 kW	$9.50/kW	$10.50/kW	$9.50/kW	$12.50/kW
2	501 to 1,000 kW	$10.00/kW	$11.00/kW	$10.00/kW	$13.00/kW
3	1,001 kW to 5,000 kW	$10.50/kW	$11.50/kW	$10.50/kW	$13.50/kW
4	**5,001 kW+**			**$13.00/kW**	**$17.00/kW**

The Joint DR Parties cite, "Feedback from customers of this size has been that with the increased cost to curtail due to the economic conditions over the last 2 years, multiple dispatches in a given year have severely diminished the economic incentive for them to participate in BIP."[8] Further explaining, "The efficiencies that come with the scale of enrolling one large site are significant from a resource point of view, and the Joint DR Parties want to ensure they are willing to continue to participate."[9] The

[7] Ex. JDRP-01 at p. 23, line 8.
[8] Ex. JDRP-01 at p. 22, line 21 - line 23; p. 23, line 1.
[9] Ex. JDRP-01 at p. 23, line 11 - line 14.

economies of scale and high reliability of larger customers is long established in PG&E's incentive structure for customers in the existing 3 tiers.

Q DO YOU SUPPORT THE JOINT DR PARTIES AND IPC PROPOSED CHANGES TO BIP INCENTIVES?

A Yes, I support increased BIP incentives given the high frequency of dispatches in recent years leading to customer fatigue and program attrition; the ongoing reliability challenges associated with extreme grid conditions; and the dramatic increase in resource costs, reflected in the 2022 Avoided Cost Calculator (ACC). For these reasons, I proposed to increase BIP incentive levels by adding an "All Other Hours" nominal $1/KW incentive for all hours that do not already have an incentive reflecting that BIP customers commit to curtail during all hours of the day, every day of the year.[10] I also agree that the proposals by the Joint DR Parties and IPC are reasonable.

In particular, the SCE incentive rates for the sub-transmission voltage class should be increased to reflect their commensurate value to the lower voltage classes, adjusted for line losses. The line losses could account for a nominally 5-10% difference in incentive levels. As proposed, the difference between sub-transmission, secondary, and primary class incentive rates is excessive. For example, the BIP 30-minute option, Sub-transmission incentive rates are ***lower*** than Secondary Service by 25% for Summer On-Peak, 64% for Summer Mid-Peak, and 38% for Winter Mid-Peak.[11]

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[10] Ex. CLECA-01 at p. 18, line 15; p. 19, line 9.
[11] Ex. SCE-04 at p.7, Table II-3.

TABLE 1

SCE BIP COMPARISON OF INCENTIVES BY CUSTOMER VOLTAGE CLASS[12]

BIP-15 minute Sub-transmission incentive percent lower than:

	Summer On Peak	Summer Mid Peak	Winter Mid Peak
Secondary	-25%	-64%	-38%
Primary	-22%	-41%	-29%

BIP-30 minute Sub-transmission incentive percent lower than:

	Summer On Peak	Summer Mid Peak	Winter Mid Peak
Secondary	-25%	-64%	-38%
Primary	-22%	-42%	-29%

Larger customers served at higher voltage are highly reliable and high load factor, and create program administrative efficiencies due to economies of scale. The sub-transmission incentive rates should be increased to a similar level to Primary and Secondary voltage classes, adjusted for line losses. I propose the Sub-transmission BIP incentive values in Table 2 below. These values are based on the incentive values for the Primary voltage class, adjusted by the ratio of loss adjusted Avoided Cost values found in column R from SCE's Workpaper titled "DR Billing Incentive Factors," which was produced in SCE's response to IPC-SCE-01, attached to this testimony as exhibit SH-01.

[12] Ex. SH-02 (attached).

TABLE 2
CLECA Proposed Sub-Transmission Incentive Levels based on
SCE proposed Primary incentive adjusted by ratio of
SCE DR adjusted Avoided Cost $/kW-yr [13]

Sub-Transmission	**Summer On Peak**	**Summer Mid Peak**	**Winter Mid Peak**
15 minute	$ 28.57	$ 4.24	$ 8.55
30 minute	$ 24.97	$ 3.71	$ 7.48

Note: credits represented by a positive number

Although there are multiple proposals for increasing incentive levels, parties representing current and potential participating customers consistently agree that higher incentives are necessary to address customer fatigue and program attrition; and the need to correct sub-transmission voltage class incentive levels.

DR MARKET-INTEGRATION

Q DO YOU AGREE WITH THE COUNCIL'S RECOMMENDATION TO ENSURE THE ADVISORY COMMITTEE FOR A DR MARKET-INTEGRATION EFFICACY STUDY INCLUDE DR PARTICIPANTS?

A Yes. The Council recommends, "With regard to the proposed advisory committee, in addition to representatives of the IOUs, Energy Division, CAISO, and CEC, as the IOUs propose, its composition should include representatives of residential and non-residential DR participants as well as third-party DR providers."[14] Robust participation from a broad range of DR participants is essential for any evaluation of DR market integration.

[13] Ex. SH-02 (attached).
[14] Ex. Council-02 at p. 6, line 1- line 4.

RESPONSE TO CAL ADVOCATES

Q WHAT IS CAL ADVOCATE'S RECOMMENDATION ON PG&E'S PROPOSED BIP EVENT LIMIT MODIFICATIONS?

A Cal Advocates recommends denying the proposed modification to adopt a 3-day maximum limit on consecutive events. They correctly identify that heat events are expected to become frequent, which is likely to lead to frequent BIP dispatches.[15] However, for that very reason, the proposed modification is necessary to address customer fatigue and program attrition. Cal Advocates conveniently omits the historically high number of BIP dispatches in 2020[16] in their discussion of recent events. Cal Advocates errs by ignoring the substantial record on customer fatigue[17] and program attrition, which has already occurred.[18] Program attrition of this reliable and cost effective resource is likely to continue without reasonable dispatch limits in light of expected high dispatch frequency.

Q WHAT IS CAL ADVOCATE'S OPINION ON SCE'S PROPOSAL TO REMOVE EVENT DAYS FROM AP-I AND BIP INCENTIVE CALCULATIONS?

A Cal Advocates questions some system upgrade costs but states that, "it is appropriate to remove event days from incentive calculations (to avoid penalizing participants from responding to multiple events within the same month.)"[19] I agree, and highlight the broad consensus on this topic.

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[15] Cal Advocates Testimony at pp. 2-4 to 2-5.
[16] Ex. PG&E-1 at p. 3-5; Ex. SCE-03 at pp. 12-13.
[17] Ex. SCE-01 at p. 18; Ex. PG&E-2 at p. 3-7.
[18] Ex. PG&E-2 at p. 3-7, Table 3-3.
[19] Cal Advocates Testimony at p. 2-8, line 5 - line 6.

Q WHAT IS CAL ADVOCATE'S OPINION ON SDG&E'S PROPOSAL TO CLOSE ITS BIP PROGRAM?

A Cal Advocates supports the proposal for SDG&E to close its BIP program, citing a limited number of industrial customers and no current participants.[20] I disagree. Given the tight supply conditions facing the state, SDG&E should instead focus on outreach to eligible existing customers and potential future customers to increase the amount of reliable and cost effective resources available to the grid. If the program is closed, SDG&E should remain flexible to accommodate existing or future eligible customers interested in providing BIP.

Q WHAT IS CAL ADVOCATE'S OPINION ON PG&E'S INITIAL DR APPLICATION PROPOSAL?

A Cal Advocates recommends adopting PG&E's alternate proposal with lower incentives, citing the higher cost effectiveness score of the alternate proposal.[21] This recommendation should be rejected. Cal Advocates bases its recommendation solely on PG&E's initial DR application, without considering the dramatically improved cost effectiveness scores included in PG&E's Supplemental Testimony from March 2023.[22] The updated cost effectiveness showings demonstrate that PG&E's initial application BIP proposal is very cost effective, with a Total Resource Cost (TRC) ratio of 2.65 with ADR.[23] PG&E's Supplemental Testimony cost effectiveness scores are dramatically improved

[20] Cal Advocates Testimony at p. 2-9, line 13 - line 22.
[21] Cal Advocates Testimony at p. 4-1, line 12 - line 16.
[22] Cal Advocates Testimony at p. 4-1, footnote 104.
[23] Ex. PG&E-7 at p. 12-9.

because of the 2022 update to the ACC, which reflects the most accurate and recent information available to determine cost effectiveness. The DR Cost Effectiveness Protocols states, "LSEs shall use the most recent version of the Avoided Cost Calculator."[24] The 2022 ACC is the appropriate measure to assess program cost effectiveness, and the updated scores support higher incentives than proposed in the initial DR applications. If **any** weight is given to the updated cost effectiveness scores by the Commission, then the alternative proposal with lower incentives should be rejected.

<u>CONCLUSION</u>

Q WAS THIS MATERIAL PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A Yes, it was.

Q INSOFAR AS THIS MATERIAL IS FACTUAL IN NATURE, DO YOU BELIEVE IT TO BE CORRECT?

A Yes, I do.

Q INSOFAR AS THIS MATERIAL IS IN THE NATURE OF PROFESSIONAL OPINION OR JUDGMENT, DOES IT REPRESENT YOUR BEST PROFESSIONAL OPINION OR JUDGEMENT?

A Yes, it does.

Q DO YOU ADOPT THIS TESTIMONY AS YOUR SWORN TESTIMONY IN THESE CONSOLIDATED PROCEEDINGS?

A Yes

[24] 2016 DR Cost Effectiveness Protocols at pp. 26-27.

Q **DOES THIS CONCLUDE YOUR TESTIMONY?**

A Yes.

Exhibit SH-01
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Recorded Average (2019,2020,2021)								Load Impact MW					DR adjusted Avoided Cost $/kW-yr	Line losses		DR adjusted Avoided Cost $/kW-yr
Customer	BIP Type	Rate Group	kVL	Interruptible MW	Average Summer On-MW	Average Summer Mid-MW	Average Winter Mid-MW	2024	Avoided Cost $/kW-yr	A factor	B factor	PRM	= AC * (A * B + PRM)	**2021 GRC**		**adjusted for losses**
												9.00%				
BUNDLED	15MIN	TOU-GS-3	SEC	2	2	0	3							**1.11004**		$116.00
BUNDLED	15MIN	TOU-8-SEC	SEC	6	13	5	22							1.11004		$116.00
BUNDLED	15MIN	TOU-8-PRI	PRI	12	30	22	50							**1.06958**		$111.77
BUNDLED	15MIN	TOU-8-SUB	SUB	127	341	341	674							**1.01653**		$106.23
DA/CCA	15MIN	TOU-GS-3	SEC	0	1	0	1							1.11004		$116.00
DA/CCA	15MIN	TOU-8-SEC	SEC	3	6	3	10							1.11004		$116.00
DA/CCA	15MIN	TOU-8-PRI	PRI	9	21	19	41							1.06958		$111.77
DA/CCA	15MIN	TOU-8-SUB	SUB	68	163	167	317							1.01653		$106.23
				228	577	558	1,117	182.1		95.50%	100.00%	9.00%	**$104.50**			
BUNDLED	30MIN	GS-2	SEC	0	0	0	0							1.11004		$116.00
BUNDLED	30MIN	TOU-GS-3	SEC	8	9	4	14							1.11004		$116.00
BUNDLED	30MIN	TOU-GS-3	PRI	1	1	1	2							1.06958		$111.77
BUNDLED	30MIN	TOU-GS-3	SUB	7	10	11	14		**$100.00**					1.01653		$106.23
BUNDLED	30MIN	TOU-8-SEC	SEC	82	158	64	251							1.11004		$116.00
BUNDLED	30MIN	TOU-8-PRI	PRI	73	114	87	199							1.06958		$111.77
BUNDLED	30MIN	TOU-8-SUB	SUB	119	190	142	322							1.01653		$106.23
DA/CCA	30MIN	TOU-GS-3	SEC	6	7	2	10							1.11004		$116.00
DA/CCA	30MIN	TOU-8-SEC	SEC	39	75	44	120							1.11004		$116.00
DA/CCA	30MIN	TOU-8-PRI	PRI	41	88	52	149							1.06958		$111.77
DA/CCA	30MIN	TOU-8-SUB	SUB	77	210	203	409							1.01653		$106.23
				452	862	610	1,490	352.5		95.50%	100.00%	9.00%	**$104.50**			
	30MIN															
BUNDLED	AGG	TOU-GS-3	SEC	0	1	0	1									
BUNDLED	AGG	TOU-8-SEC	SEC	3	6	3	9									
BUNDLED	AGG	TOU-8-PRI	PRI	3	2	0	6									
DA/CCA	AGG	GS-2	SEC	0	0	0	0									
DA/CCA	AGG	TOU-GS-3	SEC	0	1	0	1									
DA/CCA	AGG	TOU-8-SEC	SEC	2	3	2	5									
DA/CCA	AGG	TOU-8-PRI	PRI	0	0	0	0									
DA/CCA	AGG	TOU-8-SUB	SUB	16	44	43	101									
				24	57	49	122									

Exhibit SH-01

Page 2 of 2

#REF!		$000	$000			
2024		Estimated Test Year Incentives	**Estimated Test Year Incentives by season**	**Season**	**Average TOU demand - MW**	**Proposed - $/Average kW demand/month**

1.6		$181	
4.8		$552	
9.7		$1,088	
101.8		$10,816	
0.2		$23	
2.7		$314	
6.9		$769	
54.4		$5,783	
182.1		**$19,526**	
0.2		$19	
6.2		$722	
0.7		$74	
4.8		$515	
63.0		$7,304	
55.8		$6,236	
87.8		$9,328	
4.5		$518	
30.6		$3,552	
30.1		$3,370	
68.8		$7,309	
352.5		**$38,946**	

							Proposed $/Average kW demand/month					
$13,186	**SEC**			15MIN	30MIN		**30MIN**		**15MIN**		15MIN	30MIN
$8,108	Summer On	281	(28.84)	($616)	($7,492)	$375	(27.40)	($7,118)	($669)	(31.35)	21.4	259.8
$850	Summer Mid	129	(6.61)	($61)	($789)	$39	(6.28)	($749)	($67)	(7.18)	9.3	119.3
$4,228	Winter Mid	446	(9.49)	($338)	($3,890)	$195	(9.01)	($3,696)	($367)	(10.31)	35.6	410.1
$11,536	**PRI**			15MIN	30MIN		**30MIN**		**15MIN**		15MIN	30MIN
$7,094	Summer On	257	(27.65)	($1,411)	($5,683)	$284	(26.27)	($5,399)	($1,534)	(30.06)	51.0	205.5
$744	Summer Mid	181	(4.10)	($168)	($575)	$29	(3.90)	($547)	($183)	(4.46)	41.0	140.3
$3,699	Winter Mid	447	(8.28)	($748)	($2,951)	$148	(7.87)	($2,803)	($813)	(9.00)	90.4	356.4
$33,750	**SUB**			15MIN	30MIN		**30MIN**		**15MIN**		15MIN	30MIN
$20,753	Summer On	958	(21.65)	($10,919)	($9,834)	$492	(20.57)	($9,342)	($11,871)	(23.54)	504.3	454.1
$2,175	Summer Mid	907	(2.40)	($1,218)	($957)	$48	(2.28)	($909)	($1,324)	(2.61)	507.9	399.1
$10,821	Winter Mid	1,836	(5.89)	($5,840)	($4,982)	$249	(5.60)	($4,733)	($6,349)	(6.41)	990.9	845.3
			TOTAL	($21,319)	($37,153)	$1,858		($35,295)	($23,176)			
						-5%		-5%	9%			

LOLP (combined)	
2021 GRC	
61.49%	Summer On
1.86%	Summer Mid
4.58%	Summer Off
32.06%	Winter Mid
0.00%	Winter Off
0.00%	Winter Off
100.00%	

	PROGRAM	A factor	B factor
1	**BIP 15**	95.50%	100%
2	**BIP 30**	95.50%	100%
3			
4			
5			
6			
7			
8			
9			
10			

SCE Proposed BIP Incentive rates for 2024-2027

	Summer On Peak	Summer Mid Peak	Winter Mid Peak
15 minute			
Secondary	$ 31.35	$ 7.18	$ 10.31
Primary	$ 30.06	$ 4.46	$ 9.00
Sub-Transmission	$ 23.54	$ 2.61	$ 6.41
30 minute			
Secondary	$ 27.40	$ 6.28	$ 9.01
Primary	$ 26.27	$ 3.90	$ 7.87
Sub-Transmission	$ 20.57	$ 2.28	$ 5.60

Source Ex. SCE-04 at p.7, Table II-3.

BIP-15 minute Sub-transmission incentive percent lower than:

	Summer On Peak	Summer Mid Peak	Winter Mid Peak
Secondary	-25%	-64%	-38%
Primary	-22%	-41%	-29%

BIP-30 minute Sub-transmission incentive percent lower than:

	Summer On Peak	Summer Mid Peak	Winter Mid Peak
Secondary	-25%	-64%	-38%
Primary	-22%	-42%	-29%

DR adjusted Avoided Cost $/kW-yr
adjusted for losses

	$/kw-yr
Secondary	$ 116.00
Primary	$ 111.77
Sub-Transmission	$ 106.23

Source SCE Workpaper "DR Billing Incentive Factors" - column R

CLECA Proposed Sub-Transmission Incentive Levels
Based on SCE proposed Primary incentive based on ratio of SCE DR adjusted Avoided Cost $/kW-yr

	Summer	**Summer**	**Winter**
Sub-Transmission	**On Peak**	**Mid Peak**	**Mid Peak**
15 minute	$ 28.57	$ 4.24	$ 8.55
30 minute	$ 24.97	$ 3.71	$ 7.48